EXHIBIT A

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NATURAL GAS WEEK®

Vol. XXXI, No. 19 30th Anniversary May 11, 2015

NATURAL GAS WEEKLY SPOT PRICES

Flow Dates: 5/5-5/11

Price Point	$/MMBtu	Chg.	High	Low	Avg. Daily Vol.	Avg. Daily Deals	May Bid Week
GULF COAST							
ANR SE	2.73	0.16	2.77	2.68	61,214	9	2.45
Col. Gulf - Erath	2.74	0.15	2.78	2.68	92,457	9	2.45
Col. Gulf - Rayne	2.70	0.11	2.76	2.51	104,786	17	2.44
Florida Zone 1	—	—	—	—	—	—	—
Florida Zone 2	—	—	—	—	—	—	2.50
Florida Zone 3	2.83	0.18	2.88	2.74	170,593	14	2.55
Henry Hub	2.76	0.17	2.85	2.69	97,086	11	2.54
NGPL-LA	—	—	—	—	—	—	—
Sonat	2.76	0.13	2.82	2.72	97,731	11	2.49
Tenn 500 So LA Z1	2.76	0.14	2.81	2.71	50,114	4	2.49
Tenn 800 So LA Z1	2.74	0.14	2.77	2.67	92,257	6	2.45
Tetco ELA	2.74	0.17	2.76	2.67	72,700	8	2.42
Tetco WLA	2.71	0.14	2.75	2.68	4,286	1	2.45
TGT Zone SL	—	—	—	—	—	—	—
Transco Station 45	2.70	0.13	2.72	2.68	2,057	1	—
Transco Station 65	2.74	0.17	2.80	2.69	50,996	9	2.49
Trunkline ELA	2.68	0.13	2.75	2.64	8,429	2	—
Trunkline WLA	—	—	—	—	—	—	2.52
Trunkline Zone 1A	2.72	0.13	2.75	2.64	34,349	6	2.44
Regional Average	2.75	0.15					2.47
TEXAS (SOUTH/EAST)							
Carthage Hub	2.67	0.14	2.71	2.65	4,486	1	2.44
HSC	2.74	0.12	2.78	2.70	2,329	1	2.50
Katy Hub	2.72	0.17	2.77	2.67	36,543	5	—
NGPL-South Texas	2.69	0.25	2.73	2.62	7,829	2	2.49
NGPL-TexOk	2.72	0.17	2.75	2.63	129,906	14	2.45
Tenn Zone 0	2.69	0.18	2.72	2.64	41,143	5	2.45
Tetco-East Texas	2.73	0.17	2.77	2.65	14,571	2	—
Tetco-South Texas	2.74	0.16	2.77	2.67	34,614	4	2.49
TGT Zone 1	2.74	0.18	2.76	2.66	130,629	8	2.44
Transco Station 30	2.74	0.21	2.78	2.67	23,908	7	2.43
Regional Average	2.72	0.17					2.45
TEXAS (WEST)							
El Paso Permian	2.54	0.14	2.59	2.47	374,571	41	2.26
NNG Custer	—	—	—	—	—	—	—
Transwes E of Thoreau	2.52	0.15	2.58	2.49	11,971	2	2.24
Waha Hub	2.61	0.13	2.73	2.51	255,543	24	2.32
Regional Average	2.57	0.14					2.28
MIDCONTINENT							
ANR SW	2.47	0.13	2.52	2.30	14,829	3	2.27
CenterPoint East	2.64	0.13	2.69	2.53	78,629	6	2.39
CenterPoint West	—	—	—	—	—	—	—
NGPL-MC	2.64	0.15	2.67	2.56	55,171	9	2.28
Oneok	2.59	0.27	2.66	2.48	15,132	1	2.23
Panhandle	2.53	0.19	2.64	2.45	28,223	6	2.19
Southern Star	2.58	0.16	2.61	2.49	98,114	5	2.26
Regional Average	2.59	0.16					2.23
GREAT PLAINS							
Emerson	2.85	0.20	2.93	2.52	70,192	12	2.65
NB Ventura TP	2.66	0.14	2.73	2.63	6,343	1	—
NNG Demarc	2.70	0.16	2.74	2.60	72,714	9	2.39
NNG Ventura	2.66	0.09	2.73	2.62	21,243	3	2.40
Regional Average	2.75	0.17					2.45

(continued on p.2)

Devon Begins Re-Fracking Program Targeting Aging Wells in Barnett

Devon Energy is re-fracking aging wells in the North Texas Barnett Shale as it works to arrest production declines in the world's first commercial shale gas play.

The Oklahoma City-based producer pioneered Barnett development in the mid-2000s, but completion techniques have improved dramatically since then. Now, it is re-entering its early vertical wells and performing new hydraulic fracturing jobs.

"We think this re-frack program could be a potential game changer for the Barnett," Chief Operating Officer

(continued on page 1)

Inside: Special Report – Outlook for Shale Gas

Noble Shifting US Onshore Focus Away From Gassy Marcellus Shale

Noble Energy is laying down rigs in the Marcellus Shale and shifting capital away from the region as weak gas prices bite into returns.

"We are … shifting more capital in the second half of the year towards high-value areas within the DJ Basin," Chief Executive Officer David Stover said last week.

The company is reducing its Marcellus budget this year by $200 million and it will now receive just 40% of the company's $1.8 billion capital budget for the onshore US. The remaining 60% is reserved for the Denver-Julesburg (DJ) Basin in Colorado. Total global capex is holding steady at $2.9 billion.

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Drillers See a Leaner, Stronger Industry Emerging From Downturn

This year's Offshore Technology Conference 2015, one of the largest gatherings of companies showcasing new technologies in the world, was held in the shadow of a steep plunge in oil prices that adds to the pall of persistently low gas prices. But at several OTC booths and displays showcasing drilling equipment and services, *Natural Gas Week* found upbeat executives and workers reminding anyone who would listen, it's not the end.

"This is a cyclical industry," Eric Brown, general manager for Dragon Rig Sales and Services told NGW while standing next to a drilling rig that had been set up in the parking lot. "We have had downturns and we will have booms and we will have more

(continued on page 14)

NATURAL GAS WEEKLY SPOT PRICES (cont.)

Flow Dates: 5/5-5/11

Price Point	$/MMBtu	Chg.	High	Low	Avg. Daily Vol.	Avg. Daily Deals	May Bid Week
UPPER MIDWEST							
Alliance	2.74	0.13	2.76	2.68	39,386	5	—
ANR ML7	2.81	0.15	2.90	2.77	11,058	1	2.71
Chicago Citygate	2.76	0.14	2.87	2.65	438,935	42	2.53
Consumers	2.98	0.18	3.03	2.89	161,419	18	2.74
MichCon	2.99	0.23	3.04	2.92	171,235	22	2.73
Regional Average	2.85	0.17					2.68
SOUTHEAST							
Tetco M1	2.68	0.08	2.68	2.68	500	1	2.38
Transco Zone 4	2.79	0.18	2.84	2.72	239,565	21	2.49
Transco Zone 5	—	—	—	—	—	—	2.64
Regional Average	2.79	0.18					2.51
APPALACHIA							
Col. Gas App. Pool	2.76	0.17	2.80	2.60	41,232	10	2.43
Dominion North	1.59	0.17	1.75	1.46	10,008	2	1.39
Dominion South	1.58	0.14	1.76	1.45	69,892	14	1.34
Lebanon Hub	2.73	0.14	2.79	2.67	107,580	13	2.46
Regional Average	2.33	0.03					1.69
EASTERN CANADA							
Dawn	3.01	0.19	3.06	2.81	295,164	39	2.77
Iroquois	2.96	0.31	3.10	2.85	15,605	5	2.55
Niagara	—	—	—	—	—	—	1.57
Regional Average	3.01	0.21					2.66
NORTHEAST / MIDATLANTIC							
Algonquin	1.90	-0.34	2.20	1.75	78,754	12	2.35
Dracut	2.86	-0.55	3.00	2.65	3,000	1	—
Iroquois Zone 2	2.97	0.21	3.05	2.83	10,427	3	2.69
Tenn Gas Zone 6	2.03	-0.21	2.45	1.88	83,886	15	2.45
Tetco M3	1.69	0.12	1.99	1.42	123,488	20	1.48
Transco Z6 - Non-NY	2.81	0.26	2.90	2.73	74,500	12	2.46
Transco Z6 - NY	2.81	0.23	2.85	2.71	62,932	12	2.38
Regional Average	2.19	0.07	—	—	—	—	1.61
ROCKIES							
Cheyenne Hub	2.58	0.11	2.63	2.50	23,529	2	2.23
CIG	2.46	0.06	2.46	2.46	2,614	1	2.20
Kern River / Opal	2.59	0.16	2.63	2.50	196,300	22	2.26
NW Rockies	2.55	0.23	2.59	2.45	19,929	2	2.18
Questar	2.49	0.14	2.53	2.47	1,029	1	2.18
Regional Average	2.58	0.15	—	—	—	—	2.25
SAN JUAN BASIN							
El Paso Bondad	2.54	0.14	2.58	2.46	135,843	10	—
El Paso San Juan	2.56	0.13	2.59	2.49	385,943	42	2.28
Regional Average	2.56	0.13	—	—	—	—	2.28
PACIFIC NORTHWEST/WESTERN CANADA							
AECO	2.21	0.13	2.24	2.13	1,241,259	66	2.01
Kingsgate	2.50	0.17	2.56	2.43	27,514	3	—
Malin	2.64	0.15	2.66	2.50	81,329	6	2.32
NW Sumas	2.50	0.21	2.57	2.28	80,057	7	2.13
Stanfield	2.58	0.25	2.60	2.47	87,114	5	—
Westcoast Station 2	1.88	0.20	2.04	1.63	91,326	15	1.36
Regional Average	2.25	0.14	—	—	—	—	2.00
CALIFORNIA							
Kern - Wheeler Ridge	—	—	—	—	—	—	—
PG&E Citygate	3.17	0.18	3.20	3.12	245,643	21	2.90
PG&E South	2.71	0.20	2.73	2.67	107,214	7	—
SoCal Border	2.70	0.15	2.73	2.64	238,601	20	2.39
SoCal Citygate	2.85	0.20	2.90	2.81	95,446	13	2.57
Regional Average	2.89	0.21	—	—	—	—	2.61
WEEKLY COMPOSITE SPOT PRICES							
Wellhead	2.63	0.14	—	—	—	—	—
Delivered	2.48	0.03	—	—	—	—	—

Expanded Panama Canal Looks to US LNG Exporters as Key Market

By next April, a multi-billion dollar expansion of the 100-year-old Panama Canal will finally be completed and open for business, which is very good news for the LNG export terminals being built on the US Gulf Coast.

Currently, the two locks on the Panama Canal can only accommodate vessels no longer than 965 feet and no wider than 106 feet with their draft capped to 40 feet.

"That means that only 10 percent of the LNG fleet can now use the Canal," according to former Panamanian Ambassador Juan Sosa, who now serves as Panama's consulate general in Houston. "All of that is about to change, though."

During a breakfast briefing last week at the Offshore Technology Conference 2015 in Houston, Sosa said a third set of locks able to handle vessels up to 1,200 feet in length, 160 feet in width with a draft of 50 feet will be opened next year.

"This will allow more than 88 percent of the current LNG fleet to begin using the Canal," Sosa said. The Q-Max

(continued on page 2)

Murkowski Pushing Methane Hydrates R&D

US Sen. Murkowski (R-Alaska) last week introduced 17 legislative proposals regarding US energy policies including the Methane Hydrates R&D Amendments Act.

The US methane hydrate research program has been without a valid authorization since 2010. Since Congress passed the first Methane Hydrate Research Act in 2000, the US has devoted $152 million to the study of extracting natural gas from methane hydrates — naturally occurring methane molecules trapped in ice.

The potential for the US is enormous, the senator said. A conservative estimate is that onshore Alaska, the US has 85 trillion cubic feet of known hydrate reserves and 13,000 Tcf offshore in the Gulf of Mexico and Atlantic Ocean.

The Obama administration has recommended research into developing ways to tap this potential energy resource be increased. Japan is considered the world's leader in the commercial development of methane hydrates (NGW Jan.19'15).

The bill would:

- Authorize a test on land in the Arctic within four years on Alaska state lands temporarily set aside for a long-term methane hydrate production test.
- Seeks characterization of hydrate concentrations at sea within four years to obtain better estimates of the amount of hydrates in the Gulf of Mexico and Atlantic by drilling.
- Authorizes a production test at sea within 10 years, likely in the deep waters of the Gulf of Mexico, to prove that deep hydrates are technologically recoverable and identify the production technology.
- Continues all of the nation's current research on the potential climatic effects of hydrates and how to prevent seabed subsidence.

John A. Sullivan, Houston

Panama ...

(continued from page 2)
tankers will still be too large even for the new locks since they are an average of 1,132 feet long by 177 feet wide with a draft of 39 feet.

Panama also has some competition in developing a new link between the Pacific and Atlantic. In December, Nicaragua broke ground on the $50 billion, 172-mile Grand Canal of Nicaragua which the country said would be capable of handling Q-Max size LNG carriers. A Chinese company, HKND, is in charge of the project which is expected to be completed by 2020.

The current size of the Panama locks also excludes 80% of the vessels designed to carry liquefied petroleum gas (LPG) for long distances. The third lock will allow the entire fleet to transit between the Atlantic and Pacific Oceans.

The opening of the third lock will shorten the sailing time between US Gulf Coast LNG export terminals to key markets in Asia by more than three weeks. Travel times from the US Gulf and East coasts to Japan or South Korea could be shaved by 12 to 13 days each way rather than sailing around the Cape of Good Hope or through the Suez Canal.

When completed, the canal could make Panama a key regional energy hub for natural gas, said Panamanian Secretary of Energy Victor Carlos Urrutia Guardia. He said the country has the ability to develop the necessary infrastructure for storage or bunkering of LNG — though he admitted those plans were very far off.

"With LNG actually becoming a market, there might be a need for a place to do storage and Panama might be exactly in the proper place to do that," Guardia said. "We are just throwing the idea out there."

The Panama Canal Authority has set a proposed tolling structure for LNG and LPG vessels that is essentially the same as the January proposal applauded by US LNG developers (NGW Jan.19'15). The newly approved toll adjustments are scheduled to go into effect Apr. 1.

John A. Sullivan, Houston

US June NatGas Futures Soar as Spring Rally Crests Under $2.90

After a mostly down week, US June natural gas futures shot 5.3% higher going into the weekend. The prompt month gained 14.6¢ Friday to close near seven-month highs at $2.88 per million Btu — this after plumbing three-year lows in late April. Nonetheless, the bullish sentiment that has infused this month's market is being driven mainly by technical factors.

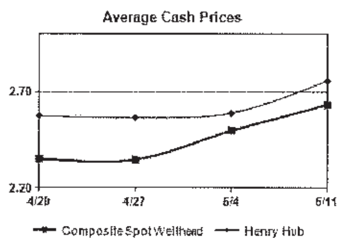
The late spring rally has been choppy, beginning Apr. 28 with a five-session 30.7¢ advance, which was interrupted by a three-session 8.7¢ retreat beginning Tuesday that drove the contract back into the low $2.70s. But the rally revived when revised late-week forecasts kicked off a recovery by promising an up-tick in demand.

"On its own, that slight addition in heating demand would not warrant a 13-cent move higher," Gelber & Associates analyst Aaron Calder said of the morning jump. "The weather model shift was the spark that lit a technical tinderbox."

While Friday's surge ignited after the contract crossed the 100-day moving average for the first time this year, bearish anchors should put a brake on how high the contract might climb.

"This is still a bullish bias in a bearish long-term trend, so expect rallies to major resistance to be sold," an EcomEnergy analysis said. The next major levels of resistance stand at $2.935 and $3.019.

Storage certainly put a damper on prices last week. The US Energy Information Administration reported a 76 billion cubic foot build for the week ended May 1, bringing working gas inventories to 1,786 Bcf. The build was just above analysts' consensus estimates, as well as last year's 75 Bcf injection, and bested the 68 Bcf five-year average build. The year-on-year surplus rose 1 Bcf to 742 Bcf, or 71.1% over last year's levels. The deficit to the five-year average fell 8 Bcf to 67 Bcf, or 3.6% below the average.



The injection implied a significant 3 Bcf/d of oversupply, Calder said, so it is noteworthy that bears could only push the contract about a nickel lower. But the spring rally that usually lasts until June should give way to a summer price slide in light of bearish trends, he said.

FirstEnergy's Martin King said last week that storage is on a trajectory to exceed 4.2 trillion cubic feet, so a 25¢ to 50¢ price drop is warranted.

The season's first triple-digit injection could come next week, with early forecasts averaging near 115 Bcf. Last year saw a build of 101 Bcf, while the five-year average is 82 Bcf.

Also, nuclear maintenance outages were fractionally lower last week, but remain at a significant level. *Natural Gas Week* data shows the potential amount of gas needed to offset off-line nuclear capacity averaged 3.5 Bcf/d, compared with 3.6 Bcf/d a week earlier.

June gas hit a high Friday of $2.888/MMBtu and was up 10.4¢, or 3.7%, for the week. Baker Hughes data shows the gas-directed rig count for the US Lower-48 states was down by one last week, bringing the total to 221 rigs.

June WTI crude moved 45¢ higher Friday to $59.39/bbl, up 24¢ for the week. Baker Hughes reported that oil-directed rigs were down by 11, bringing the total to 668, marking the 22nd consecutive week of declines.

The Commodity Futures Trading Commission's Commitment of Traders report for the week ended May 5 showed noncommercials in 66.7% short futures-only positions for the week.

Tom Haywood and Lisa Lawson, Houston

INTRASTATE WEEKLY SPOT PRICES

Flow Dates: 5/5-5/11

Price Point	$/MMBtu	Chg.	High	Low	Avg. Daily Vol.	Avg. Daily Deals	May Bid Week
Louisiana Intras	—	—	—	—	—	—	—
Oklahoma Intras	2.587	0.248	2.66	2.48	16,561	2	2.23
South Texas Intras	2.770	—	2.78	2.74	1,257	0	—
West Texas Intras	—	—	—	—	—	—	—

Governor Says Drilling Support No-Go Unless State Gets Revenue

North Carolina Gov. Pat McCrory was quick and to the point — he supports drilling in the Mid-Atlantic as long as it brings jobs and money to his state.

Speaking at the Offshore Technology Conference 2015 last week in Houston, McCrory said coastal states will support drilling near their shores but only as long as they get a share of federal oil and gas revenues.

Without those drilling dollars "it would make it very difficult for me to sell to the general public of North Carolina that we're going to get into that offshore business, but you're not going to share in that revenue," McCrory said. "We have to have the federal government agree to some sort of federal revenue sharing. Without that, you're not going to have any governors support offshore exploration."

McCrory said he sees several key reasons to drill for oil and natural gas off the North Carolina coast: US energy security, jobs creation and state revenue.

"We are not in the energy business now," he said. "But our goal is to change that."

Before drilling can begin, several things have to happen, McCrory said.

"The first is there have been no seismic surveys in this area in 25 years," he said. "We have to find out first what we have off the Atlantic coast."

For seismic testing to be successful, he said the state and federal governments will have to communicate to the public that the surveys are safe. The surveys, he said, would have to cover the coastal regions of North and South Carolina and Virginia.

"I think it is important for everyone to know that the seismic testing isn't just for oil and natural gas drilling," McCrory said. "It is also for solar and wind" explaining that the testing is needed to determine the best places to anchor offshore solar or wind farms.

But, it's revenue sharing that the governor said could be a show-stopper.

"Without revenue sharing with the federal government, it's not even on the table," McCrory said. The governor is head of the Outer Continental Shelf Governors Coalition, a group of nine state executives that lobbies for more offshore drilling and other coastal energy development.

The Interior Department's Bureau of Ocean Energy Management (BOEM) has tentatively set a 2021 auction of offshore oil and gas leases in waters off Virginia, Georgia and the Carolinas. In the current five-year leasing plan, there are only auctions planned for the Gulf of Mexico and near Alaska.

Under current law, four Gulf states — Texas, Louisiana, Mississippi and Alabama — now claim 37.5% of the royalties and other revenues that oil and gas companies send the federal government in exchange for drilling rights and production on some of their leases in the Gulf of Mexico.

According to the Interior Department, that is capped at $375 million annually, but the money for those four Gulf states is set to climb as high as $500 million annually starting in fiscal year 2017, under a law enacted in 2006.

McCrory and other East Coast governors, including South Carolina Republican Nikki Haley and Virginia Democrat Terry McAuliffe, have said the royalty revenue sharing program needs to be expanded to include the Mid-Atlantic region.

"This is where we need the most help from the federal government," McCrory said.

Also appearing on the panel with McCrory was BOEM Director Abigail Hopper. She said the states are a key player in any offshore energy development, but did not say what the White House would do.

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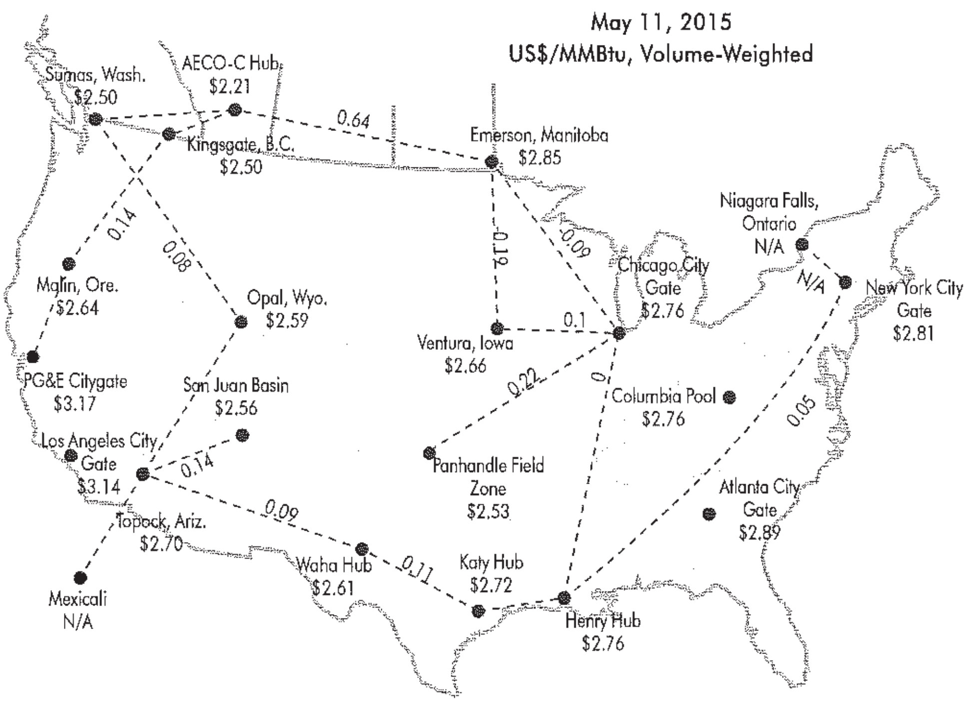
PRICES AND DIFFERENTIALS FOR MAJOR HUBS AND SELECTED CITY GATES

May 11, 2015

US$/MMBtu, Volume-Weighted



SELECTED DAILY DIFFERENTIALS

Differential	5/4	5/5	5/6	5/7	5/8
HH-NY	+0.05	+0.05	+0.04	+0.03	+0.06
HH-Chicago	-0.03	-0.02	-0.02	-0.03	+0.01
AECO-CHIC	+0.53	+0.55	+0.55	+0.58	+0.54
AECO-PG&E	+0.97	+0.96	+0.97	+0.99	+0.96

Governor...

(continued from page 4)

For the revenue sharing request to succeed, it would require action by Congress. McCrory said he has been lobbying members of Congress from both parties to add the revenue sharing language into a broader energy bill.

John A. Sullivan, Houston

Supreme Court Ruling Influences LNG Agreement With First Nation

A historic ruling by the Supreme Court of Canada giving the country's indigenous populations unprecedented control over their ancestral lands last June is already having an impact on British Columbia's nascent LNG industry, where front running Petronas and its partners at Pacific NorthWest LNG have offered landmark financial terms to the local First Nations community in an attempt to win their support.

When the Supreme Court decision was handed down just under a year ago, legal experts said the ruling was the most important Supreme Court decision ever made regarding aboriginal rights in Canada. In a nutshell, Canada's top court ruled 8-0 that First Nations have legal title to their ancestral lands unless these rights have been signed away in formal treaties. That reinforces the notion that, while the ruling affects all Canadian provinces, it will have the most far-reaching implications in resource-rich — and largely treaty-free — British Columbia (NGW Jun.30'14).

British Columbia LNG Export Locations

Last week, Malaysia's Petronas offered a financial package worth some C$1.15 billion (US$950 million) to a British Columbia aboriginal group in a groundbreaking bid to win support for a proposed LNG export terminal and pipeline on the province's Pacific coast.

Members of the Lax Kw'alaams First Nation began voting last week on whether to accept the offer, which would include cash payments totaling more than C$1 billion over 40 years, as well as a number of other inducements including jobs, training programs and scholarships.

Because the vote involves public discussions throughout the province, the vote is not expected to be finalized for at least a week, the Lax Kw'alaams said.

To further sweeten the pot, the province is offering the Lax Kw'alaams some 5,400 acres of land worth more than C$100 million near the port of Prince Rupert, where the LNG export terminal would be sited.

"Our government has been very clear that for too long First Nations have been excluded from economic development and that needs to change," British Columbia's provincial government said in a statement.

"The province is working with more than 40 First Nations to discuss benefits, concerns and the engagement process on proposed natural gas pipelines and LNG-related infrastructure within their traditional territory," it added.

The deal with the Lax Kw'alaams is the second of its kind in the past couple of weeks. Late last month, pipeline giant TransCanada announced a deal with the Kitselas First Nation related to a 600-mile gas pipeline from northeastern British Columbia — the heart of the province's rich shale gas deposits — to Prince Rupert.

Petronas is the main player behind the C$11 billion Pacific NorthWest LNG project, which would ship some 12 million

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NORTH AMERICAN WEEKLY GAS STORAGE

(Billion Cubic Feet)

Region	May. 01 Week	Apr. 24 Week	Weekly Change	Year Ago	Yr. Ago Change	5-Year Average	5-Year Change
US							
East	628	597	31	397	231	810	-182
West	368	361	7	203	165	302	66
Producing	790	751	39	455	335	777	13
Total Lower 48	**1786**	**1710**	**76**	**1055**	**731**	**1888**	**-102**
Canada							
East	51	46	5	36	15	75	-24
West	252	245	7	122	131	242	11
Total Canada	**304**	**292**	**12**	**157**	**146**	**317**	**-13**
Total North American	**2090**	**2002**	**88**	**1212**	**877**	**2205**	**-115**

Sources: Energy Information Administration; Canadian Enerdata.

Supreme Court ...

(continued from page 5)

tons of LNG per year to Asian markets (NGW Dec.15'14).

Late last year, Petronas and its partners — Sinopec, China Huadian, Japan Petroleum Exploration, Indian Oil and PetroleumBrunei — postponed making a decision on the project despite a previous assurance that they would do so if British Columbia offered new tax breaks for LNG projects.

The tentative deal between Pacific NorthWest and the Lax Kw'alaams represents a major turnaround for the LNG project on Lelu Island near Prince Rupert. A little over a year ago, the project was heavily criticized in a report written on behalf of the First Nations group for ignoring aboriginal concerns about salmon habitat.

James Irwin, Toronto

Chesapeake Boosts Output, Cuts Costs, Nonetheless Reports Loss

Chesapeake Energy reported increased production of oil, gas and natural gas liquids (NGLs) for the first quarter, but the Oklahoma City-based independent is facing financial challenges related to commodity prices that have fallen by as much as half in the past year.

The company reported a net loss of $3.78 billion for the first quarter after taking one-time charges of $3.82 billion, primarily reflecting a reduction in the value of its oil and gas properties as a result of sharply lower commodity prices.

After the write down, Chesapeake reported quarterly earnings of $42 million on revenues of $2.8 billion, down from income of $405 million on revenues of $5 billion in the same period a year ago.

Nevertheless, Chesapeake executives said the company is on track to bring its capital spending into line with its cash flow by the end of this year.

"Chesapeake is meeting the challenge of low commodity prices head-on and delivered a very strong first quarter," Chief Executive Doug Lawler said in a statement. "We remain on target to balance our capital spending and our cash flow by year-end, and the capital efficiencies that we are seeing in each of our operating areas are helping to strengthen that cash flow."

Oklahoma City-based Chesapeake predicted its combined oil and gas output would climb to between 640,000 and 650,000 barrels oil equivalent per day. Its prior forecast called for production of 635,000 to 645,000 boe/d.

Chesapeake's daily production for the first quarter this year averaged 686,000 boe/d, a year-over-year increase of 14%, adjusted for asset sales. Output remains heavily weighted toward natural gas at 2.9 billion cubic feet per day, or 12% higher than the first quarter of 2014. Chesapeake remains the second largest US natural gas producer after Exxon Mobil, whose first quarter production was 3.2 Bcf/d.

Average daily liquids production was 121,900 barrels of oil and 75,800 barrels of NGLs, up 17% and 19% respectively.

In a conference call with analysts, Chesapeake executives touted the company's enhanced well design and completion programs and improved well performance results in producing plays from the Eagle Ford in South Texas and Marcellus in Pennsylvania to the Haynesville in North Louisiana and various locales in the Midcontinent and Rocky Mountains.

Nevertheless, the company will reduce the number of rigs running nationwide from 26 to 13 over the course of the year.

For example, Chesapeake has successfully completed down spacing tests in various sections of its Eagle Ford acreage which has added up to 700 incremental locations to its undrilled inventory. The company also drilled its first three 10,000-foot laterals in the first quarter, said Jason Pigott, executive vice president of operations for Chesapeake's Southern Division.

In the Haynesville, Chesapeake is testing new completion designs, drilling longer laterals and exploiting other pay horizons. The company has drilled two 7,500-foot lateral tests with initial flow back averaging more than 17 million cubic feet per day, Pigott said.

In addition, "successful testing of our enhanced completion designs have opened up development in areas that were traditionally written off in both the Haynesville and the Bossier. The combined result of these breakthroughs is a positive production response as our production increased 4 percent this quarter," he said.

(continued on page 7)

NATURAL GAS FUTURES

Trading Dates: May 4- May 8

NEW YORK MERCANTILE EXCHANGE (NYMEX) (HENRY HUB)

	Monday		Tuesday		Wednesday		Thursday		Friday		Week's	Open
	Last	Volume	Last	Volume	Last	Volume	Last	Volume	Last	Volume	High-Low	Interest
Jun 2015	2.821	86,811	2.780	83,526	2.776	111,314	2.734	149,382	2.880	—	2.888-2.711	167,908
Jul 2015	2.878	30,822	2.836	30,899	2.828	61,654	2.785	77,183	2.928	—	2.935-2.761	202,739
Aug 2015	2.898	12,553	2.859	15,109	2.852	24,374	2.811	23,364	2.948	—	2.955-2.790	57,723
Sep 2015	2.905	11,414	2.870	13,774	2.863	18,345	2.823	24,884	2.955	—	2.962-2.801	99,599
Oct 2015	2.940	14,047	2.908	17,132	2.902	16,954	2.868	32,305	2.994	—	3.000-2.848	114,827
Nov 2015	3.036	5,434	3.009	6,267	3.005	7,143	2.979	13,188	3.092	—	3.095-2.957	53,101
Dec 2015	3.196	5,428	3.177	5,061	3.176	4,178	3.159	6,103	3.255	—	3.263-3.137	65,853
Jan 2016	3.299	8,529	3.283	7,658	3.285	10,351	3.268	14,639	3.362	—	3.373-3.242	62,532
Feb 2016	3.282	913	3.269	527	3.272	1,237	3.259	1,805	3.347	—	3.348-3.227	15,423
Mar 2016	3.229	5,418	3.220	3,657	3.226	3,686	3.213	3,637	3.295	—	3.298-3.175	37,252
Apr 2016	3.065	4,991	3.067	7,072	3.078	3,561	3.073	4,585	3.132	—	3.140-3.013	36,738
May 2016	3.068	999	3.071	719	3.082	692	3.077	722	3.131	—	3.137-3.032	11,574
12-MONTH STRIP	**3.051**		**3.029**		**3.029**		**3.004**		**3.110**			
2015 STRIP	2.894		2.875		2.872		2.851		2.926			
2016 Strip	3.188		3.187		3.195		3.189		3.248			
Total Volume		**189,929**		**195,588**		**265,533**		**353,409**		**—**		

Chesapeake ...

(continued from page 6)

"Today, we can drill wells with 7,500-foot laterals for less cost than we could drill wells with 4,500-foot laterals just a short time ago," Pigott said. Chesapeake now has 10,000-foot laterals on the schedule with completions planned for October.

Chesapeake is extending the new completion design program to the adjacent Bossier Shale play. Production there is up almost 4 MMcf/d from two tests. The company also is working on a base decline mitigation program involving the re-frac potential in the industry (p 1). Pigott said Chesapeake has drilled 6,750 horizontal wells since 2004 of which nearly 4,600 were drilled prior to 2012. The company considers these wells under-stimulated compared to current designs.

Chesapeake is conducting restimulation tests in the Barnett and Haynesville plays with very promising results. The programs are "challenged by this price environment," but work will continue on the best prospects because the payoff can be significant, he said.

In the Sussex in Wyoming's Powder River Basin, a well was drilled in 14 days at a cost of $3.2 million. The breakeven oil price in the play is $42.50/bbl. If oil climbs to $65/bbl, the rate of return would be as high as 50%, said Chris Doyle, executive vice president of the company's Northern Division.

The company's largest operating area remains the Marcellus in northern Pennsylvania even after a large asset sale of properties in the play to Southwestern Energy last year . Chesapeake's Marcellus output still exceeds 800 MMcf/d with 500 MMcf/d shut in for lack of pipeline capacity out of the region.

Barbara Shook, Houston

BSEE Director Unveils New OCS Safety Program and Annual Report

With the Offshore Technology Conference 2015 in Houston last week as a backdrop, Bureau of Safety and Environmental Enforcement (BSEE) Director Brian Salerno had two announcements — each aimed at making the Outer Continental Shelf (OTC) a safer place to work.

First out of the chute was the roll-out of the SafeOCS program, an initiative aimed at collecting and analyzing "near miss" data.

Second, Salerno released BSEE's first of what will be annual reports summarizing oil and gas activities from the past years, presents comparisons to previous years and describes the agency's analysis of trends. The report also outlines current BSEE initiatives and the agency's plans to reduce risk in the coming year.

"We are pleased to see that some of the most serious incidents offshore, including fatalities, are decreasing. But our work is far from done," he said.

"For example, the [*BSEE 2014*] *Annual Report* observes an increase in loss of well control events. That's troubling, given the potential for such incidents to have grave consequences."

In terms of fatalities, Salerno said the report shows 43 workers killed since 2007, including the 11 who died in 2010 in the Deepwater Horizon disaster. The data also shows 2,421 injuries reported over the eight-year period, a average of 302.6 per year.

"We are seeing an overall reduction," Salerno said, thanks in part to the industry and its efforts to make the OCS a safer place to work. Still, he said, "one fatality is one too many, so there is still a lot of work" for regulatory agencies such as BSEE and the industry.

As for "troubling" loss of well control incidents, Salerno said there were 47 accidents, averaging almost 6 per year. Most occurred in shallow waters, he said.

SafeOCS, an OCS near-miss reporting system, is part of BSEE's efforts to curb accidents offshore, Salerno said. The program's website will be available next month.

SafeOCS is a voluntary and confidential system, in which the federal Bureau of Transportation Statistics (BTS) will collect and analyze near-miss reports submitted by individual OCS workers, companies and others. The aggregated data will be shared with the general public through the BTS website, and used to identify safety trends and increase understanding of offshore risk.

John A. Sullivan, Houston

PIPELINE CAPACITY UTILIZATION

(Mcf/d)

Location	FlowDate	Flow	May (2015) Month-to-Date	May (2014) Month-to-Date
Transco Zone 6 NY	5/5/2015	2,014,646	1,987,154	1,837,770
ANR LA	5/5/2015	--	--	--
ANR OK	5/5/2015	543,396	560,914	596,765
Chicago Citygate	5/5/2015	2,172,426	2,097,701	2,331,940
Florida	5/5/2015	3,396,073	3,395,545	3,294,616
Michcon	5/5/2015	977,644	992,969	1,023,900
NGPL TexOk	5/5/2015	298,443	379,066	276,130
Niagara	5/5/2015	--	--	--
NNG Demarc	5/5/2015	--	--	--
Opal	5/5/2015	940,535	942,744	651,760
PEPL Haven	5/5/2015	1,178,207	1,174,780	1,142,933
PG&E citygate	5/5/2015	2,707,000	2,741,000	3,153,200
PG&E Malin	5/5/2015	1,393,977	1,398,982	1,329,289
Questar	5/5/2015	1,010,825	1,129,653	1,180,405
SoCal	5/5/2015	2,257,000	2,162,000	2,416,400

BENTEK Energy LLC

www.bentekenergy.com

Transportation Update

Natural Gas Not Only Stymied Alternative Fuel

They might not have intended it, but speakers at a Washington, D.C., forum last week put the hurdles and pitfalls of alternative liquid fuels front-and-center.

Alternative liquid fuels, like ethanol or methanol, are usually considered "drop-in" fuels that don't ask much of existing vehicle or fueling infrastructure — hence an adoption advantage over compressed natural gas (CNG) or LNG. However, "drop-in" fuels may not be as easy to "drop-in" as advertised.

At a Hudson Institute event entitled *Fueling American Growth: How Energy Independence Will Power Our Transportation Future*, speakers, such as former Shell president John Hofmeister, generally pushed ethanol and methanol — mostly eschewing CNG, LNG and electric-drive vehicle options.

Hofmeister is founder and chief executive of Citizens for Affordable Energy, one of an array of organizations that would like to see all passenger cars built as flex-fuel vehicles (FFVs) with the ability to utilize a range of ethanol and methanol blends.

The former Shell exec has endorsed other fuels in the past (NGW Mar.2'15).

After urging his audience to "educate" and "engage" yet "celebrate incrementalism" — Hofmeister's ethanol/methanol push ran up against the same chicken-and-egg dilemma seen with CNG/LNG.

Many service station contracts disallow alternative fuels — how would stations get around that? Hofmeister, citing his experience on the other side of the negotiating table, said that "if there is enough interest among dealers to push this ... they could [threaten to] throw over the brand," switch from Shell to Exxon, for example. But he did not indicate from where, or why, the interest would come.

And interest is drying up. "The reduction in [crude] prices is a significant step backward in where we need to go," he said, citing the recent $50 per barrel plunge in crude oil pricing. However, going forward, the current energy system, "run on Band-Aids and paper clips" can't keep up with growing oil demand and alternatives will be needed.

"The easiest job in the world is to say no," Hofmeister said in reference to government regulators and the hurdles they pose for ethanol and methanol.

Coleman Jones, biofuels implementation manager for General Motors, termed it "regulatory incumbency." Jones took note of the chicken-and-egg problem — even liquid fuels need to simultaneously satisfy vehicle makers, fuel makers and retailers. He cited the need for major amounts of test data for vehicles, fuel dispensers and so on.

"California stands out as having particularly restrictive regulations on the introduction of new fuels and components," according to Jones, who said there was a minimum six-year timeline for regulatory approvals there. "Losing California is a big thing," he said.

But "the ultimate regulator is the customer," in his view.

Though there are 17 million FFVs in the US, "the consumer hasn't accepted it," said Brian West, deputy director of the Fuels, Engines and Emissions Research Center at Oak Ridge National Labs.

West is a proponent of "E30" — 30% ethanol, an optimal percentage in terms of engine power. A higher ethanol blend is also a much easier way to get the large amounts of natural gas used in producing it into the transportation sector, much easier than deploying 20 million natural gas vehicles. The 17 million FFVs could provide the bridge for E30, he said.

But here again, the chicken-and-egg dilemma and regulationss pop up again.

West believes that FFVs should have been incentivized more in legislation passed back in 2007 and that incentives for dispensers should have been included. "You have to put all three forward," he said, adding fuel incentives to the mix.

Adding insult to injury, some regulations prohibit stations from going past "E25" — throwing a wrench into West's "E30" quest.

* * *

CNG offerings: Westport Innovations plans to offer 2016 Ford F-150 trucks with its Westport WiNG Power System that uses CNG.

"The F-150 with the 5.0 liter engine is a significant fleet vehicle, as fleets prefer its size, fuel economy and price," said Westport's Paul Shaffer.

The truck will be available with a 17 gasoline gallon equivalent or 23 GGE tank. Westport engineers also are evaluating underbody tank options.

Ford added an all-aluminum body last year, reducing the weight of the truck by about 700 pounds.

Michael Sultan, Washington

COMPARATIVE FUEL PRICES

(Cash Market)

May 8, 2015

APPALACHIA

Appalachian Pool Dlvd (Util)	Ohio/Big Sandy River Coal
	$47.15/ton
$2.41/MMBtu	$1.96/MMBtu

EAST COAST

New York City Gate	Heating Oil No. 2*	Residual 0.30%	Residual 1.00%
	182.43¢/gal	$61.86/bbl	$52.24/bbl
$2.02/MMBtu	$13.15/MMBtu	$9.84/MMBtu	$8.31/MMBtu

GULF COAST

Natural Gas Texas Onshore Dlvd (Util)	Natural Gas Louisiana Onshore Dlvd (Util)
$2.87/MMBtu	$2.85/MMBtu

Heating Oil No. 2*	Residual 0.70%	Residual 3.00%	WTI Cushing
$174.30/bbl	$60.80/bbl	$51.71/bbl	$58.41/bbl
$12.57/MMBtu	$9.67/MMBtu	$8.23/MMBtu	$10.07/MMBtu

Notes: (1) Residual=Residual Fuel Oil, priced exclusive of taxes; (2) WTI=West Texas Intermediate crude oil; (3) % = % of sulfur content. *Average sulfur content = 0.2%-0.5%.

Sources: Gas: Natural Gas Week; all prices volume-weighted. Oil: The weekly average of The Oil Daily's cash price postings.

Current Competition

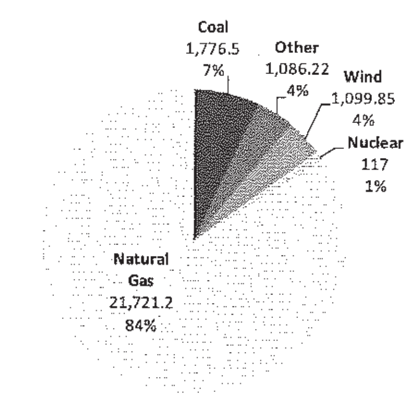
PJM Sees Gas Growth in Western Part of Footprint

PJM should continue to add "meaningful" new gas capacity to its service region, though the rate of additions is slowing, analysts with investment bank UBS said.

Over the past three years, the PJM Interconnection, a regional transmission organization that oversees 13 states in the eastern US, has added 20 gigawatts of new generation, replacing around 75% of the capacity lost due to coal plant retirements brought on by the recently rolled out Mercury and Air Toxics Standards (MATS) and weak coal-versus-gas economics, the analysts said in their recent research report *The Gas Revolution Continues*.

MATS requires large coal- and oil-fired power plants to meet stricter emissions standards by incorporating emissions control technologies in existing generating facilities. Some power plant operators have decided that retrofitting units to meet the new standards will be cost-prohibitive and are choosing to retire marginal units or convert them to natural gas (NGW Apr.13'15).

Gas Dominates New PJM Capacity



Source: PJM

At PJM's latest Grid 20/20 event, PJM Interconnection Chief Executive Terry Boston addressed growing gas capacity. "We're facing a big change from the normal pace at which the grid evolved. Looking back 80 years, typically it has taken a decade for a new fuel to emerge as a major source of generation."

PJM's mix last fall was 40% coal, 30% natural gas, 19% nuclear and 11% "other," including renewable resources, but natural gas' share is rising rapidly, representing 84% of new power projects.

UBS pointed to growth in the western part of PJM's footprint, specifically toward Ohio, which benefits from the Utica Shale. Independent power companies are replacing shuttered coal-fired generation in Ohio, with 4,000 MW of new or converted natural gas generation, which is under construction or awaiting permitting (NGW Apr.20'15).

Another large project is West Virginia's 545-MW Moundsville plant, which will use a blend of 25% ethane and 75% natural gas (NGW Feb.23'15).

UBS notes that despite the growth in PJM's western region, there is a slight decelerating trend in new entrants year-over-year in PJM, due to new Capacity Performance requirements.

"We flag that higher collateral requirements under the proposed Capacity Performance regulations would act as a barrier to entry for new PJM entrants seeking to bid into the auction," UBS analysts said.

The Capacity Performance regulations were designed in light of last winter's extremely cold weather conditions. When the severe winter storms hit the PJM region in January 2014, electricity demand soared and the region suffered widespread generator failures that peaked at about 22% of capacity, though no blackouts resulted. Generating units receive capacity payments specifically so that they will be available in these extremely high-demand situations.

PJM subsequently strengthened performance requirements and imposed harsher penalties.

PJM would like to procure Capacity Performance in all prospective auctions, setting a target of acquiring Capacity Performance to supply 80% of its total capacity needs.

* * *

Gas burns rise: American Electric Power (AEP), one of the largest US utilities, burned 15% less coal in the first quarter as it raised its use of gas-fired generation capacity. According to AEP data, the utility generated 9.9 million MWh using coal capacity, down 14.7% from the year earlier period. Meanwhile, natural gas-fired capacity produced 3.7 million MWh, up from 2.2 million MWh a year earlier.

* * *

California project: NRG Energy plans to secure approval by the end of the month for the 632-MW Carlsbad power plant in California. The company said delays in permitting could prevent the plant from entering service by the time an older plant at the site is retired.

NRG plans to shut the 965-MW Encina gas-fired plant by the end of 2017. The older plant is not in compliance with the state's once-through cooling regulation, which requires power plants to reduce water used for cooling. California has been in a years-long drought.

Lisa Lawson, Houston

SPOT ELECTRICITY TRADING

Trading Dates: May 4-May 8, 2015

POINT	Avg. Price This Week	Avg. Price Last Week	Change	Year Ago	Month Ago
COB	$35.00	$29.67	$5.33	$54.50	$24.75
ERCOT	27.80	24.33	3.47	39.00	27.50
Mid-Columbia	33.40	23.33	10.07	47.25	20.00
NEPOOL	30.20	27.17	3.03	45.75	28.25
Palo Verde	24.40	26.17	-1.77	46.50	23.50
PJM-West	53.20	36.67	16.53	49.00	38.50

Notes: (1) Prices in $/MWh. (2) Prices are for next day peak delivery. *Sources: Staff and wire reports.*

DOE Clears Cove Point Non-FTA Exports as Ferc Denies Rehearing

The US Department of Energy (DOE) has issued a final authorization for Dominion's Cove Point LNG project to export natural gas to countries that do not have a free trade agreement (FTA) with the US. The Cove Point LNG project on the Chesapeake Bay in Calvert County, Maryland is now authorized to export the equivalent of 0.77 billion cubic feet per day of natural gas, or about 5.75 million tons per year of LNG, for a period of 20 years. Exports could commence as early as late 2017.

The decision comes a day after the Federal Energy Regulatory Commission (Ferc) turned aside requests from green groups to revoke approval to build the export terminal. In its ruling, Ferc said, "A controversy does not exist merely because individuals or groups vigorously oppose, or have raised questions about, an action." One motion calling for a rehearing was filed by EarthReports, Potomac Riverkeeper, Shenandoah Riverkeeper, Sierra Club and Stewards of the Lower Susquehanna. A separate motion calling for a rehearing was filed by the Allegheny Defense Project and Wild Virginia.

In their petitions, the groups said Ferc filed an environmental assessment while it should have done an environmental impact statement. In its response, Ferc said the potential impacts from the LNG project did not warrant a full environmental impact statement. Ferc also denied BP Energy's request for rehearing, which argued that BP was unduly discriminated against by Dominion Cove Point because BP was not offered the same opportunity to turn back its Cove Point terminal capacity as Dominion offered to Statoil.

The federal agency reaffirmed its finding that the Natural Gas Act (NGA) section 7 open access terminal services provided to BP are distinguishable from the NGA section 3 non-open access terminal services provided to Statoil. Ferc added that BP and Statoil are not similarly situated and, therefore, there was no unduly discriminatory behavior.

In other legal and legislative news:

The Texas Legislature has cleared what is officially known as House Bill 40 and unofficially as the Denton Fracking Bill. It is now headed for Gov. Greg Abbott who is expected to sign it into law. The bill strips away the ability of communities to control drilling and completion techniques such as hydraulic fracturing inside their city limits — and despite the state's Home Rule Charter. The bill was written in response to the November passing of a law in Denton to stop all fracking inside the city limits (NGW Dec.8'14).

* * *

The 5th US Circuit Court of Appeals in New Orleans has tossed a lawsuit by three Mexican states against BP over the 2010 Macondo disaster. In its ruling, the court upheld a 2013 lower court ruling that because Mexico's federal government owns the affected property, the three states — Veracruz, Tamaulipas and Quintana Roo — did not have legal standing. A suit by the Mexican federal government is currently moving through the US court system.

Mergers & Acquisitions:

WPX Energy has sold a package of its Marcellus Shale marketing contracts to an unnamed buyer for $200 million. Chief Executive Rick Muncrief said the sale includes various long-term natural gas purchase and sales agreements, along with 135 million cubic feet per day of firm transportation capacity on Transco's Northeast Supply Link project.

He added that this is WPX's second transaction monetizing its holdings in the Marcellus Shale. Earlier this year, WPX completed a $300 million sale of its Northeast Pennsylvania assets. WPX's only remaining Marcellus assets in Westmoreland County in southwestern Pennsylvania remain targeted for divestiture.

* * *

Crestwood Equity Partners and Crestwood Midstream Partners are merging the two partnerships into a single publicly-traded partnership with a consolidated enterprise value of $7.5 billion. Following the completion of the merger, Crestwood Midstream will cease to be a publicly traded partnership but will survive as a subsidiary of Crestwood Equity.

* * *

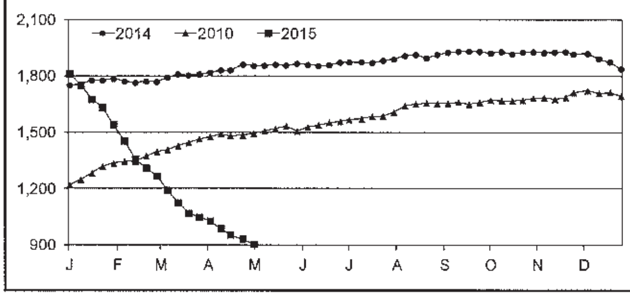
Enable Midstream Partners has completed its acquisition of $80 million of natural gas gathering assets in the Texas Panhandle from Monarch Natural Gas. The assets are supported by long-term dedication of 35,000 net acres from a

(continued on page 11)

BAKER HUGHES RIG COUNT

Week Ended May 8

Region	Current Week	Previous Week	Year Ago
Total US	**894**	**905**	**1,855**
Land	858	868	1,782
Gulf of Mexico	33	33	58
Total Canada	**75**	**79**	**145**
US Rigs Exploring for:			
Oil	668	679	1,528
Gas	221	222	323
Unspecified	5	4	4
Drilling Direction			
Directional	88	93	208
Horizontal	692	699	1,243
Vertical	114	113	404
US Rigs by State:			
California	13	14	40
Colorado	39	37	65
Louisiana	70	73	114
New Mexico	44	46	91
North Dakota	80	79	174
Ohio	24	25	35
Oklahoma	102	108	192
Pennsylvania	47	47	58
Texas	379	380	895
Wyoming	24	24	45
Major Oil Basins*			
Cana Woodford	35	38	23
DJ Niobrara	30	29	53
Eagle Ford	105	110	218
Permian	237	238	545
Williston (Bakken)	80	80	182
Major Gas Basins*			
Marcellus	66	67	84
Haynesville	27	27	45



(continued from page 10)
producer who is a current Enable Midstream customer. The 88 miles of recently built gathering pipeline and 5,000 hp of associated compression will provide gathering services to the natural gas producer drilling in Lipscomb and Hemphill Counties, Texas, as well as other producers in the area.

* * *

FMC Technologies and Total have inked a deal to define their R&D relationship and create a framework for collaborative and innovative projects.

* * *

Caliber Midstream Partners, the owner of an oil and gas pipeline network in North Dakota, is exploring a sale that it hopes could value the company at as much as $1 billion, including debt. Denver-based Caliber has more than 250 miles of pipelines in McKenzie County, North Dakota.

* * *

Gastar Exploration is selling non-core assets in Oklahoma to an undisclosed private third party for $46.2 million. The assets to be sold include 29,300 gross (19,000 net) acres in Kingfisher County, Oklahoma. Gastar estimated first-quarter net production at 170 barrels of oil equivalent per day (57% gas) from 38 gross (16.7 net) wells. The assets have proved reserves or 379,000 Boe (63% gas).

Exploration & Production:

Seattle Mayor Ed Murray ruled last week that the Port of Seattle must do a new environmental impact statement before letting Royal Dutch Shell base drilling rigs and support ships it will use in its planned Chukchi Sea drilling plan this summer. The port has said this could take several weeks.

"I don't think this will delay the program," Ann Pickard, Royal Dutch Shell's executive vice president for the Arctic, said at last week's Offshore Technology Conference 2015 in Houston.

The *Polar Pioneer* is moored at Port Angeles, Washington, while the drillship *Noble Discover* is en route to the area. During its 2012 drilling program, Shell based just about everything at Dutch Harbor, Alaska. However, any major refitting or repair work was done at the Port of Seattle.

Also Noted:

New CEOs: Occidental Petroleum has named Vicki Hollub chief executive officer; Saudi Aramco Senior Vice President Amin al-Nasser has been named acting CEO; Maple Power Capital has named To-Hon Lam CEO; Stetson Oil & Gas has named Fred Leigh president and CEO; and Sparq Systems has named Michael (Mike) J. Fister president and CEO.

* * *

Officers named: Toshiba America Energy Systems has named Robert "Bob" Temple general counsel and corporate secretary; EnCap Flatrock Midstream has named Gregory C. King senior adviser; American Eagle Energy has named Martin J. Beskow chief financial officer following the resignation of CFO Kirk Stingley; and Chesapeake Energy has named Frank Patterson executive vice president – exploration, land and subsurface technology.

GAS PRICE TRENDS

($/MMBtu)

	CALIFORNIA		ROCKY MTNS	NEW MEXICO	TEXAS				MID-CONT.	LOUISIANA			MID-WEST	APPA-LACHIA	SOUTH-EAST	NEW ENG.
	South	North			Gulf Coast Offshore	Gulf Coast Onshore	Central	West		Gulf Coast Offshore	Gulf Coast Onshore	Northern Louisiana				
May 11, 2015																
Inter (Well)	—	—	2.46	2.39	2.67	2.64	2.60	2.50	2.50	2.63	2.67	2.67	—	2.22	2.66	—
Intra (Well)	2.68	—	2.43	—	2.68	2.66	2.60	2.50	2.48	2.63	2.67	2.66	—	—	—	—
Dlvd (Pipe)	2.70	3.04	2.58	2.56	2.74	2.72	2.69	2.57	2.60	2.70	2.74	2.74	2.75	2.33	2.81	2.02
Dlvd (Util)	2.70	2.98	2.91	2.71	—	2.87	2.86	2.65	2.85	—	2.85	2.88	2.76	2.41	3.23	1.94
May 04, 2015																
Inter (Well)	—	—	2.30	2.26	2.46	2.48	—	2.36	2.36	2.52	2.52	2.49	—	2.19	2.47	—
Intra (Well)	2.53	—	2.27	—	2.47	2.50	—	2.36	2.34	2.52	2.52	2.48	—	—	—	—
Dlvd (Pipe)	2.55	2.79	2.42	2.43	2.53	2.56	—	2.43	2.46	2.59	2.59	2.56	2.60	2.30	2.62	1.97
Dlvd (Util)	2.55	2.74	2.75	2.58	—	2.71	—	2.51	2.71	—	2.70	2.70	2.62	2.38	3.10	2.25
April 2015																
Inter (Well)	—	—	2.15	2.12	2.43	2.44	2.47	2.25	2.27	2.44	2.47	2.42	—	1.90	2.43	—
Intra (Well)	2.39	—	2.12	—	2.44	2.46	2.47	2.25	2.25	2.44	2.47	2.41	—	—	—	—
Dlvd (Pipe)	2.41	2.76	2.27	2.29	2.50	2.52	2.56	2.32	2.37	2.51	2.54	2.49	2.54	2.01	2.58	2.38
Dlvd (Util)	2.41	2.69	2.60	2.44	—	2.67	2.73	2.40	2.62	—	2.65	2.63	2.56	2.09	3.04	2.88
First Quarter 2015																
Inter (Well)	—	—	2.47	2.47	2.65	2.66	2.59	2.60	2.76	2.74	2.80	2.77	—	2.39	2.75	—
Intra (Well)	2.73	—	2.44	—	2.66	2.68	2.59	2.60	2.74	2.74	2.80	2.76	—	—	—	—
Dlvd (Pipe)	2.75	2.83	2.59	2.64	2.72	2.74	2.68	2.67	2.86	2.81	2.87	2.84	3.27	2.50	2.90	6.53
Dlvd (Util)	2.75	2.82	2.92	2.79	—	2.89	2.85	2.75	3.11	—	2.98	2.98	3.30	2.58	3.29	10.40
2014 Average																
Inter (Well)	—	—	4.07	4.11	4.06	4.20	4.37	4.08	5.27	4.26	4.21	4.25	—	3.58	4.21	—
Intra (Well)	4.25	—	4.04	—	4.07	4.22	4.37	4.08	5.25	4.26	4.21	4.24	—	—	—	—
Dlvd (Pipe)	4.27	4.75	4.19	4.28	4.13	4.28	4.46	4.15	5.37	4.33	4.28	4.32	6.72	3.69	4.36	5.67
Dlvd (Util)	4.27	4.66	4.52	4.43	—	4.43	4.63	4.23	5.62	—	4.39	4.46	6.99	3.77	4.72	7.25
May 2014																
Inter (Well)	—	—	4.23	4.17	4.41	4.35	4.55	4.29	4.26	4.37	4.44	4.38	—	3.75	4.38	—
Intra (Well)	4.60	—	4.20	—	4.42	4.37	4.55	4.29	4.24	4.37	4.44	4.37	—	—	—	—
Dlvd (Pipe)	4.62	4.86	4.35	4.34	4.48	4.43	4.64	4.36	4.36	4.44	4.51	4.45	4.58	3.86	4.53	3.63
Dlvd (Util)	4.62	4.79	4.68	4.49	—	4.58	4.81	4.44	4.61	—	4.62	4.59	4.57	3.94	4.97	3.87

Notes: (1) Inter = Interstate Intra = Intrastate Well = Wellhead Dlvd = Delivered Pipe = Pipeline Util = Utility (2) This table presents historical data from the Gas Price Report. (3) R = Revised. (4) Mid-Cont. = Mid-Continent New Eng. = New England (5) Since Jan. 3, 1994, California prices have been divided into North to reflect gas delivered from Pacific Gas Transmission Co. to northern California and South to reflect gas delivered to southern California via the Transwestern Pipeline Co., El Paso Natural Gas Co. and Kern River Gas Transmission pipeline systems. Previous reporting for the state concentrated on southern California; thus, the historical prices in the South column properly reflect trading for southern California. Natural Gas Week has no similar history of prices for northern California. (6) All prices are volume-weighted.

Energy-Rich Alberta Tosses Out Conservatives

The oil- and gas-rich province of Alberta has long gloried in its reputation as Canada's most conservative province, characterized by 70 years of rule by two right-of-center parties — the Social Credit from 1935 until 1971 and the Progressive Conservatives from 1971 until last week.

The right wing reign ended when the leftist New Democratic Party (NDP) stepped out of political oblivion to capture 53 of 87 seats in the provincial legislature in Edmonton — enabling them to form a clear majority government and rule as they wish for the next four years.

Alberta's oil patch has prospered hugely since the Progressive Conservatives came to power almost 44 years ago and pinned the province's economic future on the development of its massive oil and gas deposits.

The early development of Alberta's oil patch was led by large numbers of US expatriates, mainly Texans who migrated north after World War II to work in the oil fields — and generally brought their politics along with them. When George W. Bush ended his presidency in 2009 his first public appearance was in Calgary, where he was given a rapturous welcome in the oil patch.

But as the engine of Canada's economic growth, Alberta has seen hundreds of thousands of Canadians from other provinces, as well as immigrants from around the world flock there — including the popular mayor of Calgary, Naheed Nenshi, the African-born politician who became the first Muslim mayor of a North American city in 2010.

Nevertheless, the triumph of a leftist party in Alberta last week came as a shock not only to Albertans but to Canadians across the country. After winning 12 consecutive elections by handy majorities, number 13 proved unlucky for Jim Prentice, the Conservative premier named to office last fall amid widespread certainty that he would keep the Conservatives in power for the foreseeable future (NGW Nov.10'14).

Enter NDP leader Rachel Notley, a relatively unknown Edmonton-based labor lawyer, whose father Grant was the leader of the NDP from 1968 until his death in a plane crash in 1986. When Prentice called the provincial election a month ago, the NDP had four seats in the 87-seat provincial legislature compared with 70 held by the Conservatives.

Fast forward to last week when Notley's NDP shot up to 53 seats while the Conservatives were reduced to a rump of just 10, prompting Prentice to announce his permanent retirement from politics. So bad was the rout that the Conservatives are now in third place behind the other right-leaning party, the Wildrose, with 21 seats.

But where does Notley go from here? The Alberta civil service — the people that run the province from day to day — is so entrenched within the Conservative Party after 44 years that they are practically inseparable. And in a province where energy is king, Notley has to quickly begin building ties with an industry that represents 25% of Alberta's GDP and a third of its revenues.

During her election campaign, Notley spooked the oil patch by promising to review the royalty rates paid by oil and gas companies, as well as increase the corporate tax rate from 10% to 12% and strengthen rules designed to counter global warming.

In addition, Notley said she would stop spending taxpayer dollars to promote crude oil export pipelines including Keystone XL to US markets and Northern Gateway to Canada's Pacific coast.

You can practically see members of Calgary's austere Petroleum Club sputtering in their coffee mugs. In 2007, then Conservative Premier Ed Stelmach introduced higher royalties on oil and gas production then flip-flopped three years later after being heavily criticized for making Alberta less competitive during a global economic downturn. The episode prompted his exit from office shortly thereafter.

While Notley isn't as susceptible to pressure regarding taxes and royalties, politics in Alberta still revolves around oil and gas and Notley has already offered olive branches to industry by promising not to make any changes without first hearing what the industry has to say.

Prentice was clearly a victim of weak oil and gas prices because their collapse blew a C$7 billion hole in the province's budget plan for this year and forced him to not only raise income taxes — but to cut essential services (NGW Apr.13'15).

Having been elected during the down cycle of commodity prices, Notley and the NDP can only benefit when oil and gas prices recover — although care will have to be taken by the new government not to kill Alberta's golden goose before it can lay more golden eggs.

* * *

Rig count: There were 75 rigs drilling for natural gas and oil in Western Canada as of May 4, the same as reported for the previous week by the Canadian Association of Oilwell Drilling Contractors (CAODC).

During the same period a year ago, CAODC reported that 163 rigs were drilling in the region.

A total of 758 rigs are available in the region, also unchanged from CAODC's previous report.

* * *

Working gas in all Canadian storage facilities was reported to be 39.7% of capacity as of May 1 with a 15.2 billion cubic foot injection from the week before, according to the most recent Canadian Enerdata gas storage survey.

A total of 303.5 Bcf of gas was in storage last week; capacity is 765.4 Bcf. Stores were 21.8% full a year ago.

Working gas levels in facilities west of the Manitoba-Saskatchewan border rose to 252.4 Bcf, up from a revised 242.2 Bcf the week before; capacity is 489.7 Bcf.

Working gas levels east of the border rose to 51.1 Bcf, up from 46.1 Bcf the week before; capacity is 275.7 Bcf.

* * *

The composite spot import price this week is US$2.67/MMBtu for gas leaving Canada and entering the US through six border-crossing points.

Natural Gas Week's May 12, 2014, average for Canadian exports was US$4.31/MMBtu.

James Irwin, Toronto

Israeli Official Predicts a Quick Resolution to Dispute With Noble

Despite the alarming headlines, the dispute between Noble Energy and Israeli officials impacting development of the offshore Leviathan natural gas field will be settled rather quickly, according to Neil Segel, deputy director of Israel's Economic Mission in Houston.

On the sidelines of last week's Offshore Technology Conference 2015 in Houston, Segel told *Natural Gas Week* that the anti-trust dispute is rooted in Israel's inexperience with energy.

"Israel's experience with the energy world is very limited and not very old, less than a decade," Segel said. "We have many challenges and one of them is the regulatory issues that we have created."

In January, Noble Energy suspended work on the Leviathan natural gas field off the coast of Israel after Israel's Anti-Trust Authority ruled the company and its partner, the Delek Group, had violated the nation's antitrust laws.

Together, the partners have 85% interest in the field, which could hold as much as 22 trillion cubic feet of recoverable natural gas reserves.

He said the anti-trust action was also a reaction by a country with a strong anti-monopoly history that kicked in as the "Leviathan field seemed to grow in size everyday. A lot of people suddenly became very nervous that one company could have so much control over a national asset."

Segel added that Israeli and Noble officials are working together to find a solution regarding the Leviathan field, but also to look at possible roadblocks in the future due to the country's regulations. He added that Israel is known as the "start-up" nation and that is a title it wants to keep.

"I can tell you for sure that in the next couple of months, this bump will go away," Niv Morag, manager of Water, Oil & Gas Sectors for the Israel Export & International Cooperation Institute told NGW. "Noble is in Israel to stay."

Segel added that more work is expected offshore, but don't expect a great deal of land drilling because of the nation's sensitive environmental laws.

Noble Energy also operates Israel's offshore Tamar field with a 36% working interest. Production began at the estimated 10 Tcf field in March 2013 (NGW May12'14).

John A. Sullivan, Houston

CANADIAN PRICE REPORT

($US/MMBtu and $Can/MMBtu)

	BRITISH COLUMBIA			ALBERTA		MANITOBA	ONTARIO	
	Total Province	NW Sumas Border	Kingsgate Border	AECO Hub	Empress Border	Emerson Border	Dawn Hub	Niagara
MAY 11, 2015								
Wellhead U.S. $	2.36	—	—	—	—	—	—	—
Canadian $	2.88	—	—	—	—	—	—	—
Delivered to Pipe U.S.$	2.50	2.50	2.50	2.21	2.33	2.85	3.01	—
Canadian $	3.02	3.02	3.02	2.67	2.81	3.44	3.63	—
MAY 4, 2015								
Wellhead U.S. $	2.17	—	—	—	—	—	—	—
Canadian $	2.65	—	—	—	—	—	—	—
Delivered to Pipe U.S.$	2.31	2.30	2.33	2.07	2.21	2.65	2.82	—
Canadian $	2.79	2.78	2.81	2.50	2.67	3.20	3.41	—
APRIL 2015 AVERAGE								
Wellhead U.S. $	2.07	—	—	—	—	—	—	—
Canadian $	2.59	—	—	—	—	—	—	—
Delivered to Pipe U.S.$	2.21	2.20	2.22	2.02	2.37	2.77	2.84	1.79
Canadian $	2.73	2.72	2.75	2.49	2.93	3.42	3.50	2.21
1ST QUARTER 2015 AVERAGE								
Wellhead U.S. $	2.32	—	—	—	—	—	—	—
Canadian $	2.91	—	—	—	—	—	—	—
Delivered to Pipe U.S.$	2.46	2.52	2.39	2.12	2.78	3.23	3.48	4.70
Canadian $	3.05	3.13	2.96	2.63	3.45	4.00	4.31	5.82
2014 AVERAGE								
Wellhead U.S. $	4.16	—	—	—	—	—	—	—
Canadian $	4.60	—	—	—	—	—	—	—
Delivered to Pipe U.S.$	4.30	4.36	4.14	3.58	3.99	4.77	4.83	3.82
Canadian $	4.74	4.81	4.57	3.95	4.41	5.26	5.33	4.22
MAY 2014 AVERAGE								
Wellhead U.S. $	4.19	—	—	—	—	—	—	—
Canadian $	4.58	—	—	—	—	—	—	—
Delivered to Pipe U.S.$	4.33	4.35	4.32	4.00	4.41	4.47	4.71	—
Canadian $	4.72	4.74	4.71	4.36	4.81	4.87	5.13	—

NOTES: Prices are in $US/MMBtu and $Canadian/MMBtu. Monetary conversions are done weekly. All prices represent volume-weighted averages for the most recent Monday-Sunday trading week. R=Revised.

Drillers ...

(continued from page 1)

downturns. But this time, things are different."

The reason: Foresight, he said. During previous busts since the 1980s, companies caught unprepared were bankrupt. This time around, he said "the banks are not going broke. A lot of companies were better prepared and I think a lot of companies have positioned themselves this time to come out of the downturn ready to take advantage of the upswing—when it happens."

Dragon, located in Victoria, Texas, is part of The Modern Group. The company builds drilling rigs as well as everything from pipe racks to well site systems.

"I think in the short term, everyone will see less business, so you have to fight a little more to keep what you have," Brown said. "Five years from now, I think you will see a much leaner industry—we seem to learn more from every downturn."

A short distance away, Brady, Texas-based Loadcraft Industries also had a rig set up.

While a fellow employee talked to several visitors about their rigs, Marketing Director Steve Lara told NGW that Loadcraft, which specializes in total design and manufacturing of 2,000 hp drilling and workover rigs, may be down, but it's certainly not out.

"There are still a lot of holes out there that have to be completed," Lara said. "We are seeing a lot of our customers holding off their completions and waiting for the market to rebound for both oil and natural gas."

With customers in the San Juan Basin in New Mexico to the deserts of Oman, Lara said, the company's parts sales are still solid, because it's a misconception that when companies stack a rig, "that's all there is to it. But it's not. Far from it.

"You can't just park a rig and walk away from it and go back in six months or two years and expect it to work—doesn't work that way," he said. "It has to be maintained and looked after. Otherwise, when the end of the downturn begins, they don't have any serviceable rigs ready for drilling. We are seeing a lot of work from companies needing parts and services."

Lara said Loadcraft, like many other companies in their market, are having a hard time hiring and keeping the skilled workers they need to build their drilling rigs. Specialized welders and metal workers, in particular, are always in high demand, even in a downturn.

"If you have been in this industry for a few years, you know that we are just seeing history repeat itself," he said. "Downturns happen. It is happening now and it will happen again and they always end."

HongHua America didn't bring one of its new automated rigs to the OTC, but inside the cavernous NRG Convention Center, company spokesman Andy An said they also see customers preparing for the recovery.

A subsidiary of the HongHua Group in China, HongHua America has taken a leap of faith that the downturn will end sooner than some pundits have predicted. The company has opened a 20-acre inventory storage site and facility near Houston for commissioning and rigging new rigs and refurbishing older equipment.

The company has developed what is generally called an intelligent rig, which means it uses automated systems for tasks such as loading pipe. This allows cutting a crew size down from as many as 20 workers on some sites to as few as eight to 12.

An told NGW that HongHua America has several of its automated rigs already in the hands of customers, but they are currently stacked until market conditions to improve. He added that the slowdown has given his company a chance to promote its new rigs, which are designed to work in harsh environments with temperatures as low as minus 60 degrees Fahrenheit.

The development of HongHua America's fabrication yard was not a gamble, he said, but more of a sure bet on the eventual resurgence of the US oil and natural gas E&P industry.

"Everyone knows it is coming. We are seeing a great deal of optimism out there," An said. "But, no one is going to guess when the downturn will end—just that it is coming."

John A. Sullivan, Houston

Noble ...

(continued from page 1)

The mid-year slowdown in the Marcellus was agreed to by Consul Energy, Noble's joint venture partner in the play. Noble now plans to run just three rigs in the Northeastern US shale during the second half of the year, down from six in the first quarter. The reduction will not affect Noble's production outlook because its rigs are drilling wells much faster than expected.

"Improvements in drilling times have resulted in a larger inventory of uncompleted wells than we had originally anticipated in both the operated and non-operated areas of the Marcellus," Stover explained. "This affords us the opportunity to reduce rig count in the second half of the year to one operated rig and two non-operated rigs while still meeting our planned completion and production goals."

During the first quarter, Noble produced a record-high 393 million cubic feet of gas equivalent per day in the Marcellus. Production was up 73% from the same period a year earlier and 86% of output was dry natural gas. The company's realized sales price for all gas produced in the US was $2.72 per thousand cubic feet, a 43% decrease from a year ago.

Noble is not the only producer pulling back from the Marcellus. Antero Resources is allowing its output there to slip and Cabot Oil & Gas has shut in 400 million cubic feet per day that lacks firm pipeline takeaway capacity to higher-priced US gas markets outside the Marcellus region (NGW May4'15) (NGW Apr.27'15).

The Marcellus is the highest-producing gas play in the US and accounts for 20% of the nation's gas production. Output growth has outpaced pipeline capacity, bottlenecking production in the region and causing spot gas prices in some parts of Pennsylvania to trade at a steep discount to an already depressed price at the US benchmark Henry Hub in Louisiana.

Canaccord Genuity analyst Karl Chalabala told sister publication *EI Finance* that the spot price at three main price points in northeast Pennsylvania – Leidy Hub, Millennium and Tennessee Gas Zone 4 – were just below $1.50/Mcf on May 1. By comparison the Henry Hub spot price was trading near at $2.50/Mcf.

This steep price differential explains why Noble is turning its focus toward the liquids-rich DJ Basin, where production rose 22% year-over-year to 116,000 barrels of oil equivalent per day in the first quarter. Liquids accounted for 64% of production.

Noble was operating four rigs in the DJ Basin at the end of March. The time needed to drill a well has fallen by 23% since the fourth quarter, prompting the company to say that it would drill more wells that it originally planned in 2015 and add a second completion crew.

In the DJ Basin's Wells Ranch Field, wells are being drilled in just seven days at a cost of $3.8 million to drill and complete, down from a target price of $4 million. Noble is a top operator in the DJ Basin (NGW Apr.20'15).

Rachael Seeley, Houston

Devon ...

(continued from page 1)
David Hager told analysts last week.

Devon's re-frack jobs cost $300,000 per well, which is far less than the cost of drilling a new well. Fifty vertical wells have been re-fracked so far, flowing at an average initial production (IP) rate of 65 barrels of oil equivalent per day (390 million cubic feet of gas equivalent per day). The recompletions are expected to generate a 20% internal rate of return at a gas price of $3 per thousand cubic feet and increase each well's estimated ultimate recovery by 70,000 boe.

Devon plans to re-frack 200 vertical wells across the Barnett this year. Hager said the procedure has also been performed on eight to 10 horizontal Barnett wells with encouraging results, though there are no plans for a widespread horizontal re-fracking program just yet.

The vertical recompletion program was not enough to offset the effect of declining production from Barnett wells during the first quarter. With no rigs drilling new wells in the play, output fell 10% against the year-earlier period to 191,000 boe/d (72% gas) during the first three months of the year.

Devon is one of many producers grappling with falling output from aging Barnett wells. In recent years, US gas prices have not been high enough to incentivize new Barnett drilling and producers have shifted their focus toward the lower-cost Marcellus Shale and unconventional oil plays (NGW Apr.29'15).

Data from the Texas Railroad Commission shows gas output from the entire Barnett Shale averaged 4.4 billion cubic feet per day in the first two months of 2015, down 22% from its peak of 5.7 Bcf/d in 2012.

Aside from the Barnett, the re-frack program also has potential applications in other unconventional plays.

"We've tested some [re-fracks] in the shallower portions of the Permian Basin oil play and also in the Haynesville, we're designing re-fracks right now for the Eagle Ford and the Cana Woodford projects," Hager said.

He added, "We understand that there's going to be technical challenges associated with a re-frack program – trying to control where you place the sand is going to be more difficult – but we're doing some real creative work in using science in our North Texas [Barnett] horizontal program to test both the chemical diversion and the mechanical diversion techniques and we're encouraged by the results."

While Devon experiments with the science of re-fracks, it is also moving full-steam ahead with increasing liquids production from other unconventional US plays.

The company's priorities are evident in its drilling program. Of the 30 rigs that Devon operated in North America at the end of the first quarter, half were in the oil-rich Permian Basin and the remainder was spread across oil-rich projects in the Eagle Ford Shale, Anadarko Basin, Canada, the US Rockies and the emerging Meramec play.

Devon has been in the Texas Eagle Ford for barely a year, but it is already setting the bar for wells in the play's oil-rich core. During the first quarter, five wells in DeWitt County, Texas, flowed at 30-day IP rates in excess of 3,000 boe/d.

The company's Eagle Ford output has soared nearly seven-fold from just 18,000 boe/d in the first quarter of 2014 to 122,000 boe/d in the first three months of this year.

Production is also growing in the oil-rich Permian Basin in West Texas and New Mexico. Output totaled 102,000 boe/d during the first quarter, a 12% increase from the prior-year period.

This focus on growing oil volumes is part of a broader plan to transform Devon from a natural gas-focused company into a leading US oil producer. Company-wide oil production soared 55% year-over-year to 272,000 barrels per day during the first quarter, while natural gas liquids production leaped 16% to 139,000 b/d.

Liquids accounted for 60% of total first-quarter output of 685,000 boe/d. A year ago, liquids were just 40% of output.

Company-wide gas production improved by just 2% during the quarter to 1.6 Bcf/d, with much of that growth coming in the form of associated gas flowing from oil plays.

Slumping oil and gas prices weighed on Devon's results in the first quarter. The average realized sales price for US oil production fell 53% to $42.80 per barrel and the realized US gas price dropped 43% to $2.47 per thousand cubic feet.

First quarter revenue dropped 11% to $3.3 billion. After stripping out one-time items, adjusted net income totaled $89 million, an 84% decrease from the year-ago period.

Rachael Seeley, Houston

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Market View

US NatGas Demand Set for Lumpy Growth, But Growing Nonetheless

If the gas industry ever hopes to get prices into what it considers a more sustainable price range, it can't just pull down the rig count to slash supply. After all, the whole point is to find, produce and sell as much natural gas as possible. Cutting output may raise prices but it will strangle nascent future demand.

A better long-term strategy is to grow demand for natural gas with competitive pricing and adequate supply; however, finding a way to balance supply and demand has always proved elusive. But if it were possible, current conditions are as good as it might get. Why? Domestic gas supply could be robust through 2040 and a good deal can be done in 25 years to enshrine gas as the marque fuel for power generation, as an industrial feedstock, even as a transportation fuel. And if the price is right, the US could rank among the world's top gas exporters.

Investment bank Raymond James (RJ) said in a note last week that a 6 billion cubic foot per day rise in industrial gas demand is expected between 2014-19. This would bring US demand to 26.5 Bcf/d. But this 29% rise will be lumpy, with a smallish 1.1 Bcf/d gain in 2015-16, followed by a 3.7 Bcf/d jump in 2017-18.

However, this rise seems anemic compared to the 7 Bcf/d in supply growth seen in the past six months alone, the RJ analysts said, adding that actual industrial demand growth could be smaller as "long-lead time, capital intensive construction projects ... are subject to frequent (indeed virtually endemic) delays and cost overruns."

On the positive side, once established, industrial gas demand is less susceptible than gas-fired power generation to short-term price swings, as a petrochemical or fertilizer plant does not switch feedstocks lightly.

Fortunately, rising demand wouldn't hinge on industry alone. Lower-48 LNG export capacity — now nonexistent — could approach 12 Bcf/d in about five years. But how much LNG will actually be exported isn't clear. More certain is an additional 3 Bcf/d of gas that could be flowing via pipeline to Mexico within two years, bringing total exports to Mexico to 5.3 Bcf/d.

"The Mexican government and its state run energy provider, the Comision Federal de Electricidad (CFE), has made a conscious decision to make natural gas a critical part of their nation's energy infrastructure," said PointLogic analyst Jack Weixel, noting the CFE launched five pipeline projects a year ago that would add 6 Bcf/d in incremental transportation capacity.

This is also a market that should stand firm, as Mexico's 1.3 Bcf/d demand for gas for power generation "is projected to grow exponentially over the next several years due to the installation of several thousand megawatts of increased combined cycle power plants and supporting transmission and distribution infrastructure," Weixel said.

Texas production would be a key source of supply, as well as for growing industrial demand and potential LNG exports. And with its US northern-tier markets being usurped by the Marcellus-Utica juggernaut, it would indeed be welcome.

* * *

The *Natural Gas Week* composite spot wellhead price this week is $2.63/MMBtu, 13¢ more than last week and $1.80 less than the May 12, 2014, average. The spot delivered-to-pipeline price this week is $2.48/MMBtu, 4¢ more than last week and $1.77 less than last year's corresponding average.

Tom Haywood, Houston

GAS PRICE REPORT

($/MMBtu—Spot)
May 11, 2015

	Interstate Wellhead		Intrastate Wellhead		Delivered To Pipeline		Delivered To Utility	
	This Week	Bid Week for May	This Week	Bid Week for May	This Week	Bid Week for May	This Week	Bid Week for May
CALIFORNIA								
South	—	—	2.68	2.37	2.70	2.39	2.70	2.39
North	—	—	—	—	3.04	2.62	2.98	2.62
ROCKY MOUNTAINS	**2.46**	**2.13**	**2.43**	**2.10**	**2.58**	**2.25**	**2.91**	**2.58**
NEW MEXICO	**2.39**	**2.11**	—	—	**2.56**	**2.28**	**2.71**	**2.43**
TEXAS								
Gulf Coast, Offshore	2.67	2.36	2.68	2.37	2.74	2.43	—	—
Gulf Coast, Onshore	2.64	2.38	2.66	2.40	2.72	2.46	2.87	2.61
Central	2.60	—	2.60	—	2.69	—	2.86	—
West	2.50	2.21	2.50	2.21	2.57	2.28	2.65	2.36
MID-CONTINENT	**2.50**	**2.14**	**2.48**	**2.12**	**2.60**	**2.24**	**2.85**	**2.35**
LOUISIANA								
Gulf Coast, Offshore	2.63	2.37	2.63	2.37	2.70	2.44	—	—
Gulf Coast, Onshore	2.67	2.41	2.67	2.41	2.74	2.48	2.85	2.63
North	2.67	2.37	2.66	2.36	2.74	2.44	2.88	2.58
MIDWEST	—	—	—	—	**2.75**	**2.51**	**2.76**	**2.53**
APPALACHIA	**2.22**	**1.58**	—	—	**2.33**	**1.69**	**2.41**	**1.78**
SOUTHEAST	**2.66**	**2.35**	—	—	**2.81**	**2.50**	**3.23**	**2.98**
NEW ENGLAND	—	—	—	—	**2.02**	**1.60**	**1.94**	**2.36**

	Composite Wellhead	Delivered to Pipeline	12-Month Strip Nymex
May 11, 2015	2.63	2.48	3.11
2015 Outlook	3.14	3.40	—

Energy Intelligence
A Special Natural Gas Week Supplement

NORTH AMERICAN
SHALE REVOLUTION

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Future of the US Shale Gas Revolution Not So Straight or Certain

There is no question that North America's oil and gas shale resources are immense, changing market fundamentals in ways that are hard to define. The US has gone from having a future certain of resource scarcity and dependence to one in which it stands to become a net exporter of gas as LNG and via pipeline to Mexico.

In the past 15 years, shale output in the US has risen from 2 Bcf/d to 40 Bcf/d, which is the key reason US gas production averaged 83 billion cubic feet per day in February, the last month for which the US Energy Information Administration (EIA) has released data. February output was just shy of the all-time high of 83.43 billion cubic feet per day seen in December and 8 Bcf/d more than reported for the February 2014.

A host of factors keep shale gas output elevated even as drilling activity continues to fall. Midstream infrastructure including gathering systems and processing plants are allowing a backlog of previously drilled, but uncompleted wells to be tied into the grid and large takeaway capacity pipelines will continue to add billions of cubic feet of supply in the years ahead. Reversing flow on pipes, such as Rockies Express, is also adding to takeaway capacity in the burgeoning Marcellus and Utica Shales of Pennsylvania and Ohio.

Also, as operators get more expert with drilling and completion techniques, production volumes and ultimate well recoveries rise and break-even prices fall. Much more production can be stimulated with fewer rigs. In

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SHALE PLAYS IN ABUNDANCE

Shale plays
Current plays
Emerging plays

Stacked plays
Shallowest/youngest
Intermediate depth/age
Deepest/oldest

Basins
* Mixed shale and chalk play
** Mixed shale and limestone play
*** Mixed shale and tight dolostone-siltstone-sandstone

Source: U.S. Energy Information Administration, ARI, CERI, Energy Intelligence.

Future ...

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2008, industry players held that production couldn't be sustained with prices under $7 per million Btu. Today most shale plays will flow with prices in a $4 to $5 range and record production is being maintained in a $2.50 to $3 price environment.

In both the oil and gas shale plays, E&P operators have become so good at their jobs that they are adding to an already overflowing surplus. According to the EIA, the strongest growth of natural gas production occurs in the East region, followed by the Gulf Coast onshore and the Dakotas/Rocky Mountains regions. The EIA report added that Lower 48 crude oil production shows the strongest growth in the Dakotas/Rocky Mountains region, followed by the Southwest region.

And this is where the conundrum of shale production lies. Its characteristic abundance leads to factory-like production techniques that not only drive down costs but cap price upside. Gas production in the Haynesville play in North Louisiana and East Texas has fallen even though it is the third largest gas field in the world with ample infrastructure in place. If prices were to rise north of $4, a good deal more Haynesville output would come into the money, but oversupply would then check prices and rein in production.

Additional Demand Critical

For US shale to meet its full potential, it is essential to grow demand, with LNG exports seen as the best hope. But this is also problematic. The higher the price for US gas, the less competitive it is against international oil-indexed gas prices. In fact, at recent price levels, US LNG wouldn't be going anywhere. US LNG supply would have been underwater economically and all the capacity would likely be idled.

The economics of US LNG exports looked a lot better in 2013-14. US gas pricing, plus liquefaction and transport costs, undercut Asia's oil-indexed LNG pricing by an average of $5.45/MMBtu during the first half of 2014. During the second half of 2014, due to sinking crude pricing, US gas undercut Asian oil-indexed gas by only $3.65/MMBtu.

For 2015, year-to-date, the relationship reversed with Asian oil-indexed supply undercutting US gas by about 22¢. In April, the relationship reversed again as Brent jumped back over the $60/bbl mark. US gas has regained the crown with an average 96¢ advantage since mid-April and more recently risen to around $1.30.

Even using a formula provided by LNG pioneer Cheniere, US gas would have lost out in Asia in April. Using a Brent average for April ($61.28) and a Henry Hub NYMEX average for April ($2.60), Cheniere's pricing formula, 115% times Henry Hub plus $6.50 for liquefaction and shipping, gives the company an average daily loss of 29¢/MMBtu.

Yet, Cheniere would still be raking in tolling fees estimated at about $10 million per cargo — or about $2.9 billion annually for Sabine Pass Trains 1 to 5 under contracts with international buyers.

Ironically, while low Brent pricing put US LNG out of the money in the short run, it should prove beneficial for US LNG in the long run and hence bullish for shale gas demand post-2020.

The Brent price collapse is tangling up non-US LNG projects and leaving room for cheaper-to-build US brownfield and/or small-scale projects designed to join a "second wave" of US LNG in the next decade.

And despite a worldwide slowdown in liquefaction final investment decisions (FID), US-based LNG projects still have forward momentum.

Freeport LNG has wrapped up financing and started construction on its $4.2 billion, 4.4 million ton per year, Train 3, on Quintana Island near Freeport, Texas. Full operation of the three-train, 13.2 million ton/yr facility (1.8 billion cubic feet per day) is now expected by the third quarter of 2019.

FIDs have now been made for four US LNG export projects including Sabine Pass (Trains 1-4), Cove Point, Cameron (Trains 1-3), and Freeport. US FIDs amount to 48.4 million tons/yr of LNG capacity, which will put the US among the top LNG exporters in the world by the end of this decade.

Cheniere's second project, Corpus Christi LNG, is expected to make FID sometime before May 15, which would add another 13.5 million tons/yr to the US capacity total. Sabine Pass Trains 5 and 6 received US Federal Energy Regulatory

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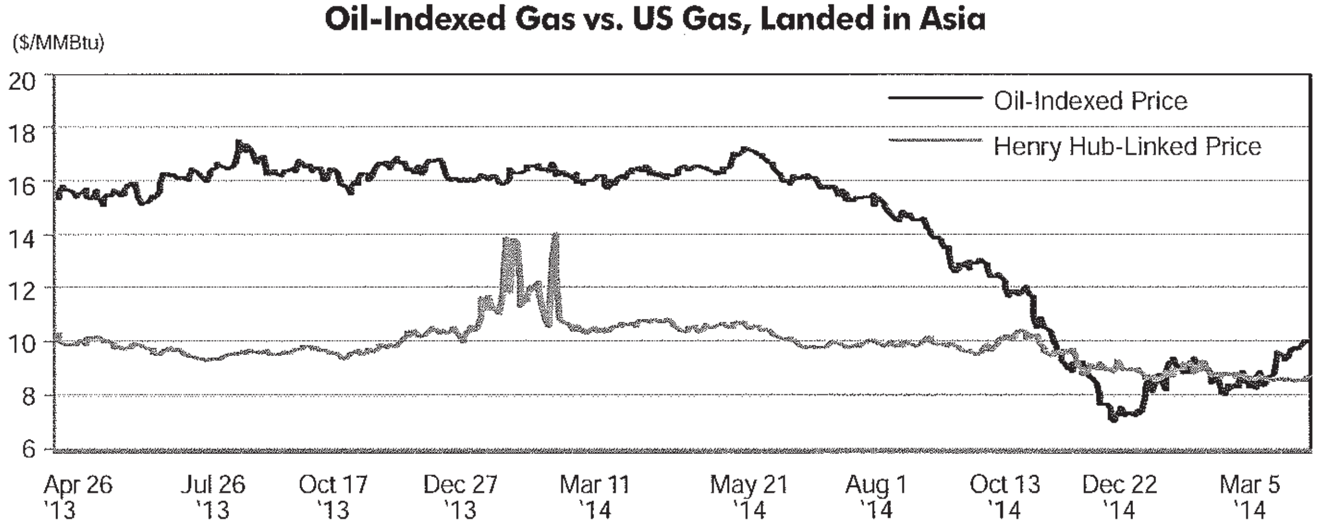
Oil-Indexed Gas vs. US Gas, Landed in Asia



Source: Reuters, *Natural Gas Week* data

Future ...

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Commission approval last month, which would add another 9 million tons/yr. Another 10 million tons/yr is very possible from a proposed Cameron LNG expansion.

Additional export projects are also making progress. By 2020, there could be 86.9 million tons/yr of capacity (11.9 Bcf/d) — potentially almost 1.5 Bcf/d of gas more than world leader Qatar exports today.

Industrial Renaissance

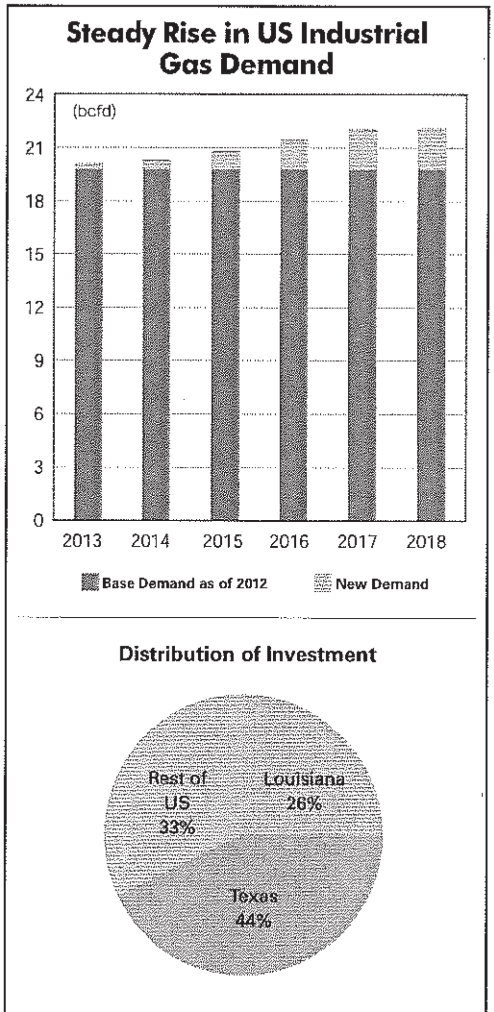
After flat to declining natural gas demand over the first decade of the 2000s, US industrial consumption is on the rise again. By the end of the decade, industrial natural gas use could rise to 23.3 Bcf/d, the highest volume in more than 20 years, according to the Center for Energy Economics at the University of Texas Bureau of Economic Geology (BEG).

The 23.3 Bcf/d is BEG's high case forecast volume. The reference case sees demand climbing to 22.1 Bcf/d, which still is 2.3 Bcf/d higher than in 2012, the University of Texas department said in a report.

One difference between the two is the number of projects involved and the types of ventures included. The high case included 112 projects representing a total investment of $98 billion. The reference case represents 83 ventures with a combined value of $65 billion.

The BEG limited its survey to major gas-consuming industries such as ethylene, the basic petrochemical building block, fertilizer and methanol. The biggest sector is ethylene, which includes four ethane crackers under construction in Texas and one in Louisiana.

The BEG identified around $14 billion of investments in other industrial sectors, of which 60% were outside Louisiana and Texas and not gas-intensive operations.



Source: The University of Texas Center for Energy Economics

US industrial gas consumption dropped to 17 Bcf/d in 2009, according to EIA data. This followed both the Great Recession and several years of soaring domestic prices after multiple hurricanes and normal attrition had shrunk US supplies.

What turned the market around was the shale gale. US gas supplies began rising, bringing natural gas liquids (NGLs) volumes along with them. Inexpensive natural gas and NGLs relative to their prices in the rest of the world and to those of oil brought a renaissance to the US petrochemicals industry as well as to fertilizer production.

BEG chief economist Michelle Foss said the biggest challenge the US petrochemical industry now faces competing in the international market is the strong dollar, not falling oil prices. "I don't think they can survive a really strong dollar for a really long time," Foss said.

Strong interest rates could present a problem, too, she continued, which may be why many companies are arranging financing ahead of construction startup dates and before the US Federal Reserve raises interest rates as expected later this year.

The strong dollar offsets some of the value of inexpensive fuel and feedstock, said Deniese Palmer-Huggins, senior energy advisor at the bureau. At the same time, the prices for NGLs, especially ethane, are still flat and at a low level around 19¢ per gallon, less than $11 per barrel or one-fifth the price of a barrel of oil.

"With ethanol at 19¢/gal, I don't see projects being canceled," Palmer-Huggins said.

Most of the fertilizer capacity expansion is expected in the farm belt and accounts for almost all the industrial projects not in Texas or Louisiana, or 33% of the new projects.

Texas, a shale and conventional gas powerhouse, is the biggest beneficiary of the investments, getting 41% of the $65 billion in the reference case. The four ethane crackers make up the vast majority of the total dollar amount. The remainder is an assortment of ethylene-derivative plants and related petrochemical plants and methanol producers.

The dollar amount directed for Louisiana has declined significantly from the first estimate released last year because of Sasol's cancellation of a proposed natural gas-to-liquids (GTL) plant.

Ethylene plants, including expansions, upgrades and new-builds, account for 24 separate projects in the BEG count for a total value of $41 billion. Not all of these may be built, but of those now on the books, 11 are expansion projects either already complete or going forward.

The next largest portion of investment is $26 billion in 29 fertilizer plants. Several projects are already completed, including a restart, a couple of expansions and a new facility. More than half are in progress.

Around $11 billion is going into some 11 methanol projects. Only eight of them are new. Two of them are relocations from overseas. One is a restart.

The EIA's outlook goes much further out, as far as 2040. The near-term view sees growth of 1.3% annually through 2025, then dropping off to only 0.2% per year for the final years of the forecast. "Increased international competition slows industrial production growth and energy efficiency continues to improve in the industrial sector over the long term," the EIA said.

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Future..

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In the medium to long term, what happens in the industrial sector will depend in large part on what happens in the shale, and not enough is known to draw a conclusion, yet, says BEG's Foss.

For example, she asked, what will happen if shale gas production drops off more quickly than expected? Or if companies' balance sheets prove weaker than predicted? Or if future light tight oil discoveries don't come with as much associated gas and associated light liquids?

There are additional problems facing the industry looking to raise demand for gas-fired power even as the US is becoming more efficient in its energy use. In its *Annual Energy Outlook 2015*, the EIA notes declining energy use due to more energy-efficient technologies, as well as the effect of existing policies that promote increased energy efficiency.

Greens Weigh In

But the free market isn't the only factor holding sway over continued success of the nation's shale plays.

From green-led voter fights to statewide bans on hydraulic fracturing to the specter of growing federal regulation , shale operators are facing uncertainties beyond those caused by low prices.

For the operators, the tallest hurdle that's only rising is from local and state lawmakers across the country. The latest legislative challenge has come from the small town of Washington, Connecticut. While the town and the state may not be on the E&P industry's radar, the vote is indicative of the legislative challenges across the country.

The town's Selectmen's Office has voted to disallow waste disposal related to hydraulic fracturing from shale plays. The move was pushed by the Washington Environmental Council, which has similar movements under way in five other Connecticut communities.

While no pushback is expected against the Washington vote, the same cannot be said for a move by the citizens of Denton, Texas, who voted in November to ban any new wells that use hydraulic fracturing inside city limits. The action prompted lawsuits and moves by state lawmakers that would take away the ability of communities to regulate drilling inside their political boundaries.

Texas House Bill 40, known as the "Denton Fracking Bill," has cleared through both the Texas House and Senate and it is expected to be signed into law by Gov. Greg Abbott. The bill, filed in response to the Denton vote, will block efforts by communities to control drilling or completion techniques such as fracking inside their city limits. Another bill being considered by Texas legislators would force communities that enact fracking bans to repay the state any royalty monies that it might have missed because of the measure. A similar dispute in Ohio over local control was decided by the Ohio Supreme Court, which said state rules can trump local ordinances.

However, despite this pressure from state lawmakers, at least 11 Texas communities are studying green-led challenges to drilling inside their jurisdictions.

Meanwhile in December, New York Gov. Andrew Cuomo's administration made that state's ban on hydraulic fracturing permanent, with officials saying the available science surrounding the drilling method was insufficient to determine risks to public health. This ban caused a few counties in New York's Southern Tier prospective for Marcellus Shale development to suggest joining Pennsylvania.

Yet even in neighboring Pennsylvania — center of the Marcellus Shale juggernaut — shale operators are facing new rules for oil and gas drilling from the administration of Gov. Tom Wolf. The proposals rolled out in March call for waterway protection; require a different permitting track for wastewater; require operators to submit plans for active, inactive, orphan and abandoned wells and create noise control and mitigation standards. The proposals also update reporting.

However, grassroots efforts are where the major green groups are looking to find the most traction. Greenpeace USA spokesman Jesse Coleman told Energy Intelligence that efforts like the Denton campaign are becoming preferred method of rejecting "the short-term gains and long-term negative impacts offered by shale drilling."

If successful, such efforts would have the E&P industry facing an ever-growing patchwork of laws and regulations from the smallest hamlet to the largest city and from state to state. To combat this Balkanization of drilling regulations, the US would have to create some type of national energy policy or body, said former Shell Chief Executive John Hofmeister.

At the recent Nape conference in Houston, he warned, however, that such a national body has little chance of being created.

Despite the attention that high profile fracking bans in New York State and the city of Denton have garnered, a outright nationwide ban on the activity looks much less likely than a few years ago. The US Environmental Protection Agency is expected to come out with a report in coming weeks on hydraulic fracturing's potential impact on drinking water. But from a regulatory perspective, the agency looks to be largely out of the picture when it comes to regulating underground injections related to fracking because of a provision in the 2005 Energy Policy Act known as the "Halliburton loophole".

However, while a ban is unlikely, there are signs that industry may face a more complex regulatory picture in the future. In March, Interior Department Secretary Sally Jewell announced regulations on hydraulic fracturing that will require drillers to disclose the chemicals used in fracking; set standards for well-bore integrity; and store frack water in above ground storage tanks rather than lined pits.

For now, those rules only apply to operators on tribal and federally-owned lands. But Jewell has said she believes the rules could be used as a model for states that are new to oil and gas activity. Moreover, attorneys general in North Dakota and Wyoming have sued, saying that because of the ways federal and state-regulated lands overlap, the rule all but assures states must adopt the regulations as their own.

And while the EPA is congressionally prevented from regulating fracking, the agency is responsible for overseeing the disposal wells used to handle large volumes of wastewater produced as drilling has taken off. An April US Geological Survey report connected disposal wells to the startling rise in seismic activity in 17 areas in eight different states. In February, an EPA-led report recommended new approaches for regulators deciding whether or not to authorize additional disposal wells. Still, EPA administrator Gina McCarthy said shortly after the USGS report that her agency did not have any immediate plans to address the seismic concerns with further regulatory action.

Tom Haywood, Barbara Shook and John Sullivan, Houston, with Michael Sultan and Emily Meredith, Washington.